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Transitioning towards a 100% solar-hydro based generation: A system dynamic approach

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ABSTRACT

Many countries have targeted a gradual transition towards 100% green generation; however, there is uncertainty concerning the economic and social consequences of such a transition. The main technologies that have been implemented are hydro, wind and solar. The latter two could cause an increase in electricity prices due to a mismatch between demand and supply. This paper uses a system dynamics approach to analyze the transition process of Switzerland, which is gradually moving from nuclear towards solar and hydro base generation. We consider hydro-pumped storage to address the timing problem between supply and demand. We developed different scenarios to test the viability of such a system. Our findings indicate that leaving the system to a free market will entail shortages during the transition, as well as a doubling of the electricity price. To mitigate this effect, we propose a capacity auction mechanism to smooth the transition process. We find that subsidizing PV indirectly encourages storage, thereby eliminating shortages, and mitigating the increase in the electricity price during the transition.

1. Introduction

Electricity systems across the globe are facing the challenge of transitioning towards low-carbon electricity generation [1–3]. Thus, many countries are considering policies that encourage the use of Variable Renewable Energy Sources (VRES), such as sun and wind. VRES has increased sharply over the last decade due to technological progress, government incentives and economies of scale [4,5]. While in 2009 the total renewable installed capacity was of the order of 1150 GW, at the end of 2018 it had reached 2378 GW [6].

A high share of VRES in the electricity mix reduces flexibility and security of supply [1,7], making it challenging to balance the market at all times. To solve the mismatch between the seasonal and daily patterns of demand and supply, energy storage has been used [8,9]. Today the most used energy storage technology is hydro storage. Conventional hydro storage plants rely on natural water inflows; adding pumping mitigates the limitation and variability of natural inflows [10].

Any transformation of the electricity system must be accompanied by efficiently designed policies that drive the desired transition smoothly. The challenge that arises is how to achieve the desired transition while considering factors such as electricity security and costs. Traditionally researchers have focused their studies of sustainable transition on the supply angle. Markard (2018) draws attention to the acceleration of energy transitions, which creates challenges (for instance, the decline of established business and decentralization of the electricity system) that require new approaches from policy makers and researchers. From the demand point of view, studies have focused on demand side response, demand reduction, and distributed energy, among others [12].

The aim of this paper is to explore different pathways for a transition towards 100% greengeneration. We develop a stylized simulation model of an electricity system which consists of a base load (e.g., run-of-river), a technology that is being phasing-out (e.g., nuclear), an intermittent technology introduced to replace the phased-out technology (e.g., PV) and an energy storage technology (e.g., pumped hydro-storage).

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Our objective is to gain understanding of the feasibility of a transition towards a 100% renewable electricity system. We focus on the long-term consequences of such a transition, exploring the impact on blackouts, electricity price and required capacity. More specifically, we aim to understand whether a market-driven transition is possible, or whether governmental intervention (e.g., through subsidizing of capacity investments) is required to achieve a smooth transition. We conclude that such a transition is technically feasible, but government intervention is essential to insure sufficient investments. A key insight of our model is that, while a smooth transition requires investment in both PV and pumped hydro-storage (PHS) to be profitable, this can be achieved by subsidizing only PV. Indeed, the build-up of a large PV capacity creates a profitable environment for investments in PHS.

This generic model can be calibrated for different regions and technology mixes. Our goal is to develop a model to test the appropriateness of different energy policies that target a smooth transition towards renewables. In this paper, we calibrate the model using the Swiss context to identify the challenges and potential solutions, with one important caveat: we assume that the jurisdiction aims at being self-sufficient with respect to generation, i.e., there is no reliance on an integrated regional market, nor imports, to satisfy demand. This assumption, which is a limitation to the generality of our analysis, could be relaxed by including imports and exports as respectively additional generation capacity and demand. Given the objectives of our analysis, i.e., understanding the transition, this would not affect the main insights of our work, unless we explicitly modelled a regional market. We assume, as stated above, that jurisdictions have a political desire to be self-sufficient should a regional market be unable to deliver the agreed amount of electricity. The COVID-19 pandemic has recently illustrated the risks of relying on imports in a very different, but equally crucial setting: medical care. Indeed, the sharing of supplies of personal protective equipment at the start of the pandemic [13], and more recently of vaccines [14], among European countries has been all but smooth.

This paper is structured as follows. In section 2 we review the relevant literature. In section 3 we present the Swiss context. This is followed by a discussion of the methodology and the model description in section 4. Section 5 presents the simulation results and scenarios. Finally, section 6 provides conclusions and policy recommendations.

2. Literature review

Three strands of literature concerning electricity transitions towards a high share of RES are relevant for our work: policy mechanisms, energy storage and electricity models [15].

There are different types of policies that encourages investments in VRES and they can be classified in two main groups: direct (DP) and indirect instruments (IP). DP target an immediate stimulation of investment in VRES, while IP aim to improve the long-term context, so VRES expands gradually [16]. DP can be subdivided into two groups: price or quantity driven. The most commonly used strategies are investment focused (e,g,. investment subsidies) and generation-based strategies (for instance, Feed-in Tariffs (FITs) or a fixed price premium). Besides regulatory mechanisms, there are also voluntary actions to promote VRES which rely on the willingness of consumers to pay a fee for green electricity [16].

VRES have been encouraged by tax incentives, investment subsidies and production incentives. A statistical analysis based on U.S. data concludes that these three policy tools are positively correlated with investment in wind energy generation capacity [15]. However, subsidies are controversial. It has been argued that they bias the market (e.g., they can lead to investments in inefficient projects) and prevent the development of markets for renewables by creating a mental model that renewables should be subsidized or even free [16]. Barradale (2010) and Carley et al. (2017) agree that such subsidies tend to be temporary, and dependent on public support [1,19]. The resulting political uncertainty decreases investors' confidence, thereby reducing the government's ability to secure power investment agreements.

FITs have been the most commonly used tool in Europe to promote the expansion of VRES and are a well-established policy that has been used to limit the risk for investors [20]. They induce innovation in initially costly energy technologies, such as solar power [21]. Nicolli and Vona (2019) suggest that FITs enable new agents to enter the electricity market, thus limiting the power of incumbents, which reduces entry barriers [22]. On the negative side, FITs can lead to investors not responding to price signals from the market, thus distorting the market (e.g., over investments) and reducing the consumer welfare [23].

Capacity auctions for VRES are a policy mechanism where the regulator defines the capacity or the generation that must be available at a certain moment in time. Under this mechanism, companies submit a bid with a price (required subsidy) per unit of capacity or per unit of generation at which they are willing to install new capacity [20]. Lucas, Ferroukhi and Hawila (2013) argue that the main advantage of auctions is to guarantee a known fixed subsidy per unit of installed capacity. Another advantage is to increase competition, thereby revealing the true market price; capacity auctions also improve the predictability of renewable generation. The disadvantages discussed in the literature are: high administrative costs, underbidding, collusion between agents, and increasing entry barriers for medium and small agents [20,23,24].

There has recently been a shift from the previously predominant model of feed-in-tariffs (FiT) towards capacity auctions, which are considered to be a more competitive or market-based way to subsidize renewable energy. This evolution has been observed, among others, in Germany, where pressure from the EU and industry has changed the way renewables are subsidized [25]. However, FiT schemes have the advantage of also being suitable to encourage smaller installations, e.g., households and communities, whereas capacity auction are more appropriate for large installations [26].

Energy storage becomes necessary for electricity markets that aim to have a high share of VRES. Although balancing supply and demand is done largely at a primary energy input level (e.g., hydro reservoir when geographically possible), storage can occur at the grid level (e.g., batteries) and at the level of the consumer [27]. The main technology currently used is hydro storage, which can quickly adjust generation, thereby providing flexibility to the system. Adding pumping to a hydro-storage plant mitigates the limitation and variability of natural inflows [10].

Schill & Zerrahn (2018) review 33 models which consider different types of storage [28]. They conclude that, while there is no consensus in this literature, some insights do emerge. First, energy storage becomes an economically viable option to integrate high shares of renewables when renewable deployment reaches between 50 and 70%. Second, for intra-day storage, batteries are useful to smooth the variability of wind and PV. Finally, interseasonal power storage (for instance through pumping or hydrogen storage) only becomes economically viable for 100% renewables systems.

Many studies have shown that energy system transitions have to take into account not only technical feasibility, but also how the interaction between regulation, markets and strategies of different actors shape the transition [11,29]. Li et al. (2015) propose the concept of socio-technical energy transition (STET) models. STET models extend quantitative models with elements of socio-technical transitions such as policies, agent behavior and technological evolution. STET models must capture the interaction between demand, supply, investment decisions, regulation and delays [30].

3. The Swiss context

We choose Switzerland for two reasons: the dismantling of nuclear plants over the next 25 years [31], and the opposition to the construction of thermal plants [32]. The dismantling of nuclear capacity over the next decades raises the question of how this generation will be replaced: how will the Swiss electricity system meet national demand after 2019, when the first nuclear reactor will be dismantled and how much will this transition cost [31]?

To answer these questions the Federal Council has developed the Energy Strategy 2050, which draws the path the electric system should follow. This strategy aims to increase efficiency, decrease energy consumption and incentivize the use of VRES [33]. The main measures being proposed to enable the implementation of this strategy are the liberalization of the electricity market for small consumers, which should lower the consumer price, and the introduction of a storage reserve which will increase the security of supply [34].

Currently, the total installed generation capacity in Switzerland is 20.2 GW. Hydropower represents 75%, nuclear 15% and the remaining 10% include cogeneration plants and PV [35]. The average annual electricity production over the last decade was 67 TWh, with hydropower accounting for 58%, nuclear for 36% and thermal and renewable plants for the remaining 6% [36]. The average annual demand over the same period was 61.9 TWh, indicating that Switzerland is a net exporter: the average annual exports (imports) were 33 TWh, (31 TWh) [37]. The maximum hourly demand registered was 9.9 GW and the lowest 4.2 GW [38]. Consequently, as the hydro generation installed capacity is twice the hourly peak demand, as long as there is water available, Switzerland can always meet the peak demand. With hydropower being the main generation technology, water in the reservoirs becomes a strategic resource. The minimum fill rate is typically reached at the end of March, while the maximum occurs at the end of September. Reservoirs are thus used to store excess water during late spring and summer, to be used in late fall and winter [39]. As mentioned in the introduction, we deviate in one important dimension from the Swiss case, in that we do not consider imports and exports, i.e., we assume that there is a desire to be self-sufficient. This hypothesis could be relaxed by treating imports and exports as additional demand or generation capacity.

The Swiss government has been encouraging wind farms and PV projects with Feed-in Tariff mechanisms since march 2008 [40]; installed capacity has increased by 2.3 GW while wind installed capacity increased by only 51 MW [33]. PV installed capacity is expected to continue increasing in the coming years.

The increasing PV entails an excess of energy during the day, especially in summer. This disequilibrium between generation and demand can be resolved by curtailment, exports or storage. Storing the excess has become a priority in systems which are transitioning to a high share of renewables. Pumping is not new in Switzerland and has been used to provide intra-day and inter-seasonal storage capacity. In 2019 the total generation of pumped hydro-storage was of the order of 4.3 TWh, representing 6.7% of the total electricity consumed in Switzerland [37]. Assouline, Mohajeri & Scartezzini (2017) evaluate the potential of PV generation to be of the order of 32 TWh by 2050. Technological evolution, including the installation of floating panels on water reservoirs, could push this figure even higher [42].

Hydro-generation is limited not by the generation capacity, but by water availability. Increasing reservoir capacity would facilitate dealing with the seasonality of inflows, thereby increasing hydro-generation in winter. By increasing the height of current reservoir dams, a 10% storage capacity increase could be achieved [43].

4. Methodology and model description

Electricity markets are complex as they involve many factors and actors that interact, creating feedbacks in the presence of delays. We therefore model the system's structure explicitly. This kind of modelling provides understanding of the dynamics of the industry, which is particularly important for policymakers during periods of transition. We propose a System Dynamics (SD) based model. SD is useful to incorporate feedbacks and delays into the model [44,45], which allows understanding the behavior of the system by studying its structure.

SD based simulation models have been used extensively to study the impact of energy policies [46]. They provide the possibility to explore the possible outcomes of changes to the underlying system before these are implemented. This methodology has been used to study regulatory changes. SD has been used to analyzed the impact of introducing a high share of renewables [47,48]. Castaneda et al. (2017) explore the effect of introducing a high share of rooftop solar generation (prosumers); they find that, in the long-run, rooftop solar can generate death spirals in electricity markets.

Energy transitions have also been discussed in the SD literature. For instance, Bunn et al. (1998) discuss how SD is useful to improve the understanding of systems facing a transition [49]. Olsina, Garces, and Haubrich (2006) propose a model to evaluate the long-term dynamics of deregulated electricity markets [50]. They show that regulatory mechanisms need to be implemented as early as possible so that the required capacity is available, and prices remain stable. Finally, SD has also been used as a decision support tool to study investment decisions. Ochoa (2007) build a SD model to study investment dynamics for Switzerland [51], while Kilanc and Or (2008) developed a decision support tool to study investments, pricing, and regulation in a decentralized electricity market [52].

4.1. Model formulation

This model was developed to explore different pathways for a transition towards 100% greengeneration. We aim to study the appropriateness of capacity auctions. Our goal is to test if this policy allows to manage the transition from a system with a significant share of nuclear generation to a system based only on PV and hydro. In this section we provide an overview of the model, focusing on the intuition behind the model. To provide this overview we use a causal loop or feedback diagram (Fig. 1), which shows the main concepts of the model and visually illustrates how they are interrelated [42]. The appendix provides a full documentation of the model, including all equations, parameter values and a graphical representation of the non-linear relationships.

Causal look diagrams use a "+" or "-" next to an arrowhead to indicate the causal relationship between two variables. A "+" sign indicates that if the cause variable increases, the effect variable increases as well, while a "-" sign indicates that if the cause variable increases, the effect variable decreases [44]. The two parallel lines on an arrow indicate a lag. The clockwise arrow indicates a feedback loop. A "B" indicates a balancing or negative loop: an increase in one variable, traced around the loop, will lead to a further decrease of that variable, generating a balancing behavior.

The key (state) variables (installed capacity of PV and pumps) are represented by the two rectangles. The model has three balancing loops, which we describe in turn. The first feedback loop

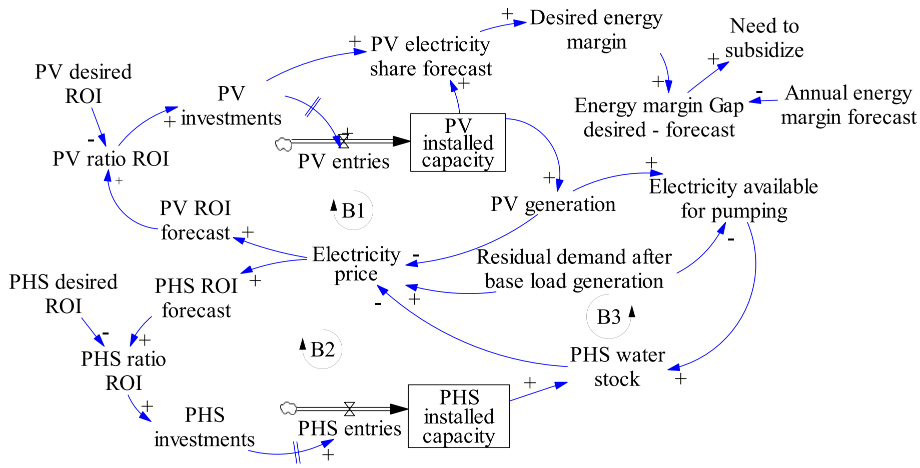

Fig. 1. Main variables and relationships of the proposed model.

(B1) represents investments in PV capacity. An increase in PV capacity will increase the generation of electricity from PV, which, due to the low OPEX, will lead to lower electricity prices. This in turn reduces the forecast of future electricity prices, resulting in a lowering the return of investment (ROI) compared to the desired ROI; this will reduce investments in PV, thereby slowing down, or even halting new PV capacity coming on-line, as current projects are gradually completed.

The second loop (B2) captures the dynamics of PHS pumping capacity in a similar way: an increase in pumping capacity allows for more water storage, leading to lower electricity prices and thus lower profitability and eventually fewer investments in pumping capacity. Note that this loop is characterized by significantly longer time-lags, as the construction time for PHS is significantly exceeds that for PV, with two consequences. First, once the price is sufficiently attractive to encourage PHS investments, it will take a considerable time for this new capacity to come online, compared to investments in PV capacity. Second, even though, following capacity coming online, the electricity price falls below that required for investment, capacity will continue to increase as projects under construction continue to come online; indeed, it is unlikely these will be cancelled once launched.

The third loop B3 captures the interaction between PV and pumping. An increase in PV installed capacity leads to more electricity being available for pumping and thus more water in the reservoirs. The higher the water level, the lower the electricity price and hence the lower the PV and PHS profitability, which discourages investments, as discussed in the two previous loops.

The final element of the model represented in Fig. 1 is the determination of the amounts of subsidies needed to ensure enough capacity to satisfy demand, with an appropriate energy margin**.** Note that we do not use the capacity margin due to the high share of hydropower; instead, we use the concept of energy margin [53]. The energy margin gap represents the deficit of energy required to satisfy the annual forecasted electricity demand, i.e., the difference between expected demand and supply. This gap is influenced by the desired energy margin, which itself depends on the share of PV. Indeed, in the presence of a large share of intermittent generation (PV in our model) a more important energy margin is required to achieve the same level of security of supply. This increases the requirements for new capacity which trigger the necessity of subsidies.

As outlined above, both B1 and B2 show that investment decisions depend on the comparison between the desired ROI and the ROI forecast. To calculate the latter, we run a second version of the model in parallel, a shadow model which forecasts generation and electricity prices three years ahead (i.e., the time required to build capacity), assuming that demand and water inflows remain unchanged. This shadow model is used to calculate the future expected price and generation by technology, yielding the ROI forecast.

The annual excess energy is calculated as the difference between the total hydro-storage availability (natural hydro and pumping) and the annual unmet demand after base-load, nuclear and PV. A negative energy margin indicates a shortage, while a positive energy margin indicates an excess of energy. The regulators compare the forecasted energy margin with the desired energy margin. The latter depends on the share of PV generation: the higher the PV share, the higher the desired margin. The regulator will subsidize PV when the forecasted energy margin is lower than the desired one: we calculate the subsidy per MW of capacity that makes the investment in PV attractive, capturing the idea of a capacity auction.

We use a typical day to represent each month and capture seasonal and daily patterns of sun irradiation, demand and supply. This simplification implies that we ignore day-to-day variability. Recall that our objective is to analyze a long-term transition towards 100% renewable electricity generation. Consequently, our focus is on long-term patterns, as opposed to short-term operational behavior. While daily variations play an important role in the latter case, they do not affect our long-term conclusions. Seasons are defined as follows: winter (December—February), spring (March—May), summer (June—August) and fall (September—November).

For non-hydro technologies, the bids are calibrated so as to achieve an economically viable system, i.e., they are based on the levelized cost, so as to cover both the fixed and variable costs. The hydro-storage bid price additionally depends on the water level in the reservoir, and the PHS bid price is further influenced by the purchase price of water. We assume that run-of-river and nuclear are dispatched first, followed by solar, and finally hydro-power: a merit-order dispatched is used to prioritize PHS and hydro-storage. The electricity price is set by the bid price of the most expensive dispatched technology. The levelized costs (parameters) are given on the table in Appendix A.1.2.2.

We focus on investments in pumping capacity (not generation capacity) because generation capacity is used jointly by PHS and hydro-storage, and Switzerland already has enough hydro-storage generation capacity to match peak demand. We initially assume a linear nuclear capacity dismantling process to focus our analysis on

Table 1
Data sources and assumptions.

Input	Source	Data and hypotheses
Electricity demand, electricity generation, installed capacity, dam's water level and pumping facilities	[35,36,56–60]	Historical data from 2010 to 2019
Solar irradiation	[61]	We build an hourly curve for a representative day per month.
Solar cell efficiency	[62]	We assume 20% efficiency.
Losses from PHS	[63]	We assume 80% efficiency.
Marginal and capital costs	[64]	Costs are exogenous and constant.
Nuclear capacity		Nuclear capacity is being dismantled linearly over the period 2025–2040.
Hydro-storage and run-of-river turbine generating capacity; Hydro-storage and reservoir size.	[60]	We assume an exogenous and constant installed generating capacity, i.e., no dismantling of, nor investments in capacity. The same hypothesis is made for the size of the hydro-storage reservoirs.
Planning and construction process for PV and PHS	[65,66]	We assume a total investment time (project planning, obtaining the permits, and construction) of 3 years for PV and 2 years for PHS (only pumping capacity, storage capacity is assumed to remain constant).

the transition process, rather than on how a system reacts to sudden changes in capacity.

We assume no cross-border exchange of electricity. The Absence of exports leads to excess generation at the start of the simulation. While we are aware of the increased international collaboration in Europe and the growth in cross-border electricity trade [54], our aim is to understand what is needed for a country such as Switzerland to achieve a transition towards self-sufficient green generation. Indeed, Switzerland's neighbors will also move towards a high share of VRES, including a significant share of solar. This will entail European-wide electricity excesses and shortages at certain times.

The simulation model was developed in Vensim DSS 7.3.4. The simulations run from 2020 to 2040. Table 1 summarizes the data sources used to calibrate the model and the main assumptions. We perform the traditional tests to validate SD models [55], which include a link-by link validation of the model, checking the dimensional consistency of each equation and carrying out extreme condition tests to ensure model robustness. The model has successfully passed these tests and also respects basic physics laws such as mass and energy balance. Moreover, we perform an extensive sensitivity analysis, which is summarized in section 5.1. The model is calibrated using secondary data bases, presented in Table 1, which are mainly based on current Swiss conditions. Recall that we study the transition for a country aiming to be self-sufficient, i.e., we do not consider imports and exports. As Switzerland currently imports significant volumes in winter, and exports similar volumes in summer our simulation results not be validated against historical data.

5. Simulation results

We consider a base case scenario in which there are no subsidies, i.e., investment in PV generation and pumping capacity is driven by the market. Fig. 2a shows the PV, nuclear and pumping capacity over the simulation period. Recall that nuclear capacity dismantling is exogenous. The rapid increase in pumping capacity during the first years results from the excess of electricity generation at night (see Fig. 2b): the availability of inexpensive electricity increases the ROI of PHS, encouraging investments. PV increases in anticipation of future nuclear dismantling. Fig. 2b also shows that the investments in PV and pumping capacity are not enough to avoid shortages (and thus blackouts) in winter from the middle of the simulation period onwards.

Shortages lead to an increase of the electricity price. Fig. 3 shows the evolution of the electricity price and the reservoir fill rate, which are inversely correlated. As the reservoir fill rate decreases, the electricity price increases.

5.1. Sensitivity analysis

We assume that the parameter values presented in Table 1 remain constant over the simulation horizon. In reality these are likely to change. We therefore aim to test the robustness of these insights by exploring the impact of key parameters such as natural water inflows, reservoir size and PV capital cost, as well as the speed of the nuclear dismantling process. PV capital cost and natural inflows are conditions that are not controlled by the regulator. The first one depends on the development of the technology, while the second one depends on climate variations. The regulator can influence the length of the nuclear dismantling period and the size of the reservoirs.

Table 2 shows the parameter changes considered for each of the eight sensitivity tests. For instance, " $\pm$15%" means that this parameter is increased/decreased by 15% compared with the base case.

All sensitivity scenarios show shortages. We consider two measures to evaluate their extend: the severity of shortages when they do occur (measured as the % of unsatisfied hourly demand during the hour with the worst shortage) and the frequency of shortages (measured as the % of hours per year with a shortage). In almost all cases, the worst shortage occurs in 2035. The only exceptions are the scenarios N^+ and N^-, in which the worst year is 2030 and 2040, respectively.

Table 3 summarizes the results of the sensitivity analysis and compares these to the original scenario (denoted B^0). These results show that the water inflows and the length of the nuclear dismantling process have a significant impact on the frequency of shortages. All parameters tested have a negligible impact on the maximum unmet demand (measured as a % of hourly demand). The maximum hourly shortage always occurs in February. As shown in Table 3, this shortage takes place in 2036–2040, except for the scenarios N^- and N^+: decreasing (increasing) the length of the nuclear dismantling shifts the year with the maximum shortage to 2040 (N^-) and 2031–2040 (N^+) respectively.

Next, we consider the impact on price. To facilitate interpretation, we consider the ratio between the electricity price of each scenario and the base case price, as shown in Fig. 4. A ratio above (below) one means that scenario has a higher (lower) price than the base case. Fig. 4 shows how four scenarios have prices lower than B^0 (N^+, I^+, $C^{-0.1}$ and $C^{-0.25}$). N^+ and I^+ imply more generation, respectively due to more nuclear installed capacity (N^+) and has an increase in the natural inflows (I^+). Both $C^{-0.1}$ and $C^{-0.25}$ have a lower capital cost, leading to a lower bid and thus a lower price than the base case. These four scenarios reduce blackouts leading to a price ratio lower than 1. In N^-, nuclear capacity decreases faster, while in I^- the natural inflows are lower; both scenarios lead to more blackouts due to lower resources, and thus to higher prices.

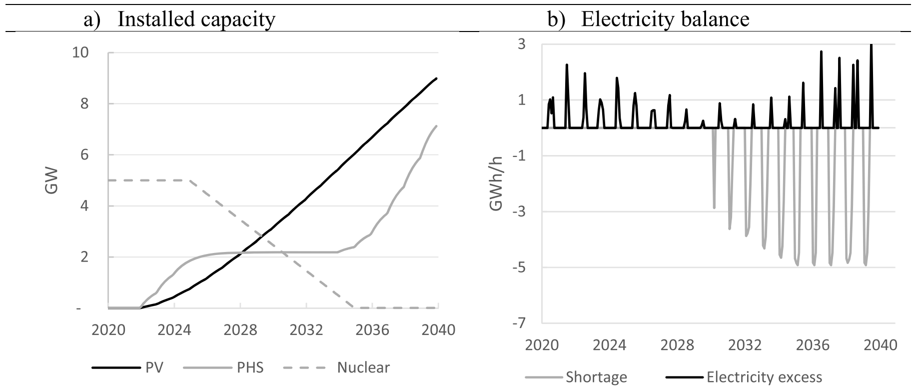

Fig. 2. Installed capacity and electricity balance in the base case scenario.

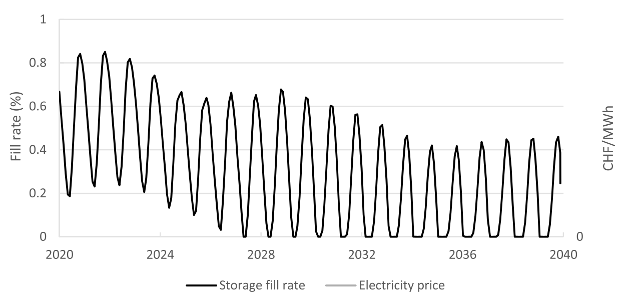

Fig. 3. Reservoir fill rate and electricity price in the base case scenario.

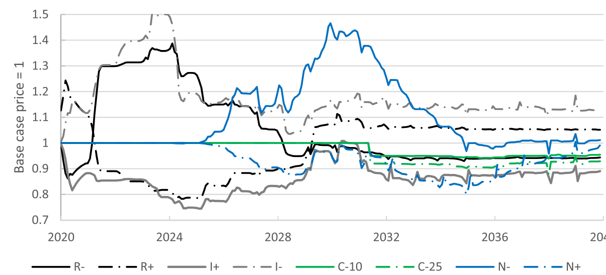

Fig. 4. Electricity price ratios (base case = 1).

Table 2
Sensitivity analysis parameters.

Parameter	Name	Change
Natural inflow	I^+,I^-	±15%
Reservoir size	R^+,R^-	±10%
PV capital cost	$C^{-0.1}$, $C^{-0.25}$	−0.5%/year, −1.25%/year
Length of the phasing-out period	N^+,N^-	2025–2040, 2025–2030

Table 3
Sensitivity analysis results for shortages - base case.

Case	Years with blackout	Maximum number of hours with a shortage		Maximum hourly unmet demand	
		%	Year	%	Years
B^0	2030–2040	36%	2036	71%	2036–2040
N^+	2033–2040	24%	2040	69%	2040
N^-	2028–2040	45%	2030	71%	2031–2040
$C^{-0.1}$	2030–2040	35%	2036	71%	2036–2040
$C^{-0.25}$	2030–2040	34%	2036	71%	2036–2040
R^+	2031–2040	36%	2036	71%	2036–2040
R^-	2028–2040	36%	2036	71%	2036–2040
I^+	2032–2040	26%	2036	68%	2036–2040
I^-	2028–2040	43%	2036	74%	2036–2040

The remaining scenarios (R^+ and R^-) exhibit a more complex pattern. A smaller reservoir size (R^-) results in a higher fill rate of the reservoir and thus the price at which hydro bids initially decreases (2021). After one year the smaller reservoir size leads to an inability to store enough water to avoid blackouts during the winter, and thus the electricity price increases. This increase in price incentives PHS investments, so after 2028 the price ratio drops below 1. R^+ exhibits an opposite pattern compared to R^-. At the start, R^+ has a lower water fill rate which, leads a decrease in the price ratio after 2020. After 2021 as the reservoirs can store more excess electricity, the electricity price stays low until 2030: having the ability to store more energy discourages PHS investments, so when the dismantling process reaches a point where the supply is unable to match demand, the price ratio goes above 1.

We also tested the impact of the linear nuclear phase-out hypothesis, replacing it with a more realistic step function: we divide the phasing-out process into three equal-sized discrete steps. Fig. 5 shows the results for the main variables of the model. Fig. 5a shows that the electricity price increases significantly at each step. In Fig. 5b we observe the energy margin forecast decreases three years before the step, as expected this triggers chunky investments; as a consequence, the energy margin increases in anticipation of each step, and decreases at the time of the step. Fig. 5c shows the energy balance. While the excess is similar for both scenarios, this is not the case for the shortages. In the linear case shortages start around 2029 (the year where the energy margin turns negative, see Fig. 5b), while for the step case shortages already start around 2026, just after the first chunk of nuclear capacity is retired. After 2026 the shortages decrease until the next step, when the shortages increase again. Fig. 5d shows no major differences between a linear function and step function for the installed capacity and the electricity balance. These results allow us to conclude that our model is robust with the pattern of the nuclear dismantling process.

5.2. Capacity auctions

The previous analysis points to insufficient investments in PV and PHS capacity to avoid blackouts. Fig. 6 shows the evolution of the annual energy margin for the base case. This figure shows an initial increase due to the excess of energy, followed by a linear reduction, along the pattern of nuclear dismantling.

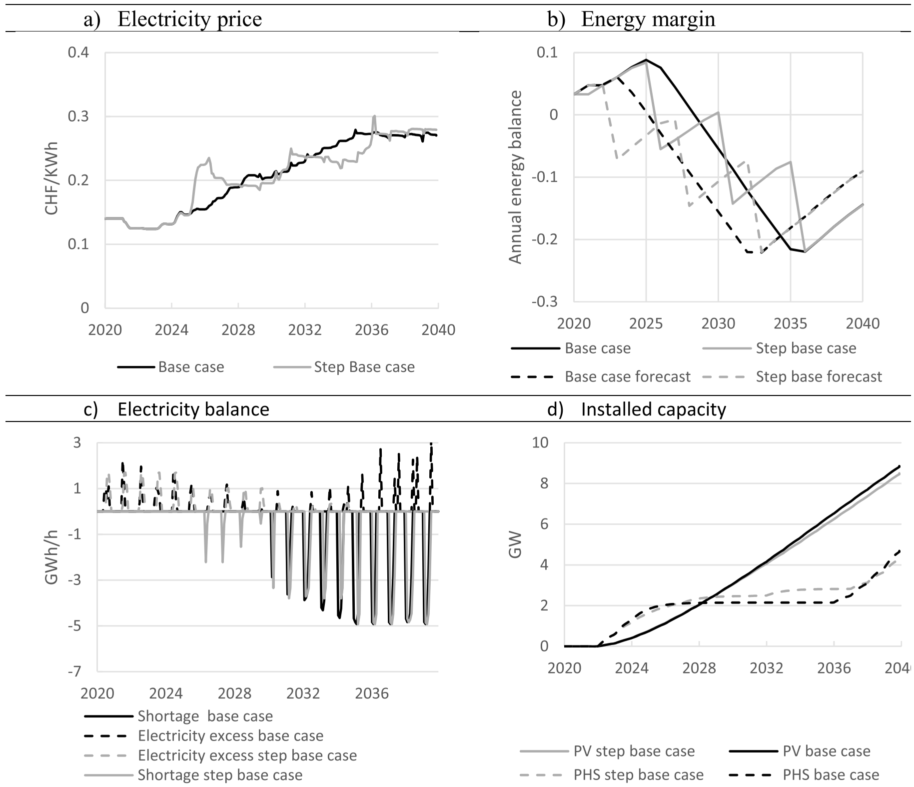

Fig. 5. Nuclear dismantling (step vs linear function).

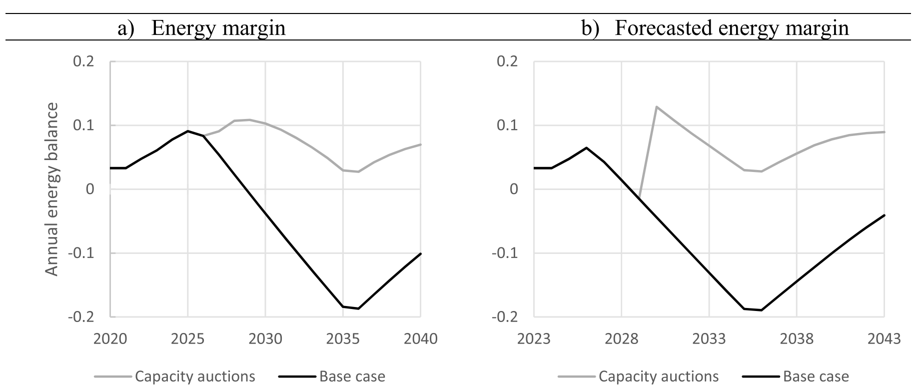

Fig. 6. Annual energy margin and forecasted annual energy margin.

Fig. 6a shows the evolution of the energy margin and Fig. 6b shows the forecasted energy margin (i.e., the value shown for 2023 is the value that was forecasted in 2020). A negative forecasted energy margin predicts insufficient energy to meet demand (see Fig. 6b after 2028). This is a signal for the regulator that there is need for action, and that an intervention is required to avoid blackouts. We consider one policy mechanisms to encourage investments, capacity auctions (CA), which triggers investments, leading to more installed capacity, and thus a higher energy margin (see Fig. 6a after 2026).

Fig. 7 captures the evolution of PHS and PV installed capacity. We see that CA have the expected effect on the system: PV installed capacity grows rapidly due to an increase of PV ROI. At the end of the simulation, PV installed capacity is 66% higher than in the base case. We also observe that the pumping capacity increases by 34% compared to the base case. When CA is implemented, blackouts are eliminated, and the total annual excess electricity equals 9% at the end of the simulation.

Fig. 8 shows the evolution of the electricity price. During the first year we observe a constant price, but over the next four years price decreases due to the introduction of PV capacity in anticipation of the nuclear dismantling process. Next, in 2025, as nuclear capacity is being dismantled, the electricity price starts to increase for both scenarios. In the base case the electricity price continues to increase until the end of the nuclear dismantling process (2035). This increase responds to shortages (recall Fig. 2), as the hydro bid depends on the reservoir level: when there are shortages, the reservoir is almost empty, so the hydro bid is at its maximum, which increases the electricity price. In the CA scenario, the regulator incentivizes investments in PV to avoid shortages. The

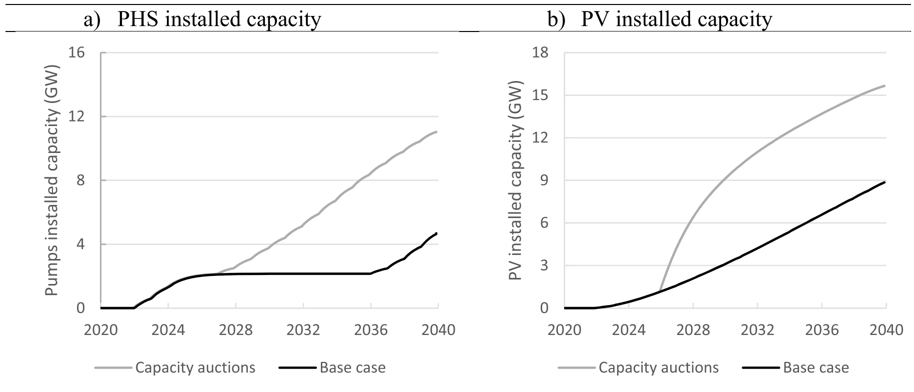

Fig. 7. Installed capacity of PV and pumps by scenario.

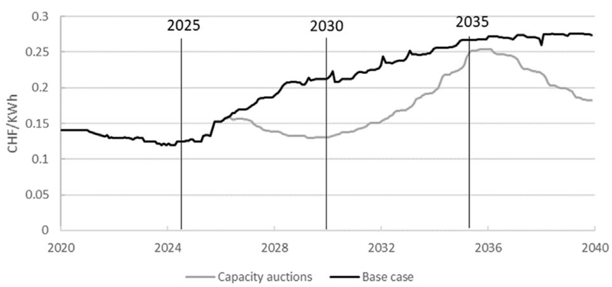

Fig. 8. Electricity price.

increase in both PV and pumping capacity (recall Fig. 7) leads to a reduction in the electricity price between 2025 and 2030. The higher the PV capacity, the higher the excess of cheap electricity that can be pumped.

Fig. 9 illustrates the interdependency between the evolution of PV installed capacity and the ROI of PHS. The base case illustrates how PHS is unprofitable when PV capacity is low; this technology only turns profitable once there is enough PV installed capacity (in 2036, when PV installed capacity reaches 7 GW and PV generation represents 26% of total generation). To be profitable, PHS needs to maximize the difference between the prices at the time of pumping and of generation. Fig. 9 also illustrates how subsidizing PV indirectly encourages investments in pumping capacity: the increasing PV installed capacity leads to inexpensive excess electricity, which increases PHS's ROI.

PHS profit also depends on its utilization rate, the evolution of which is shown in Fig. 10a. We can observe that after 2024 the utilization rate is higher with CA than in the base case, as there is more electricity available for pumping, therefore subsidizing PV indirectly encourages PHS. Fig. 10b shows how subsidies maintain

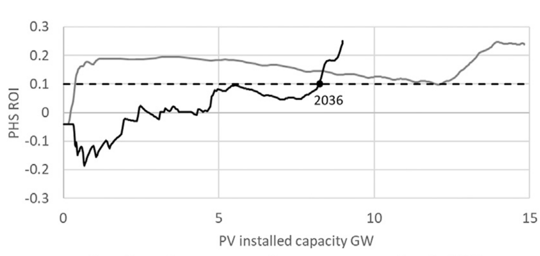

Fig. 9. PV installed capacity versus PHS ROI.

the fraction of hours per year the pumps operate above 30%, while in the base case, this fraction falls after 2024, reaching a minimum of 8% of the total hours of the year in 2034. Note that CA results in more PHS installed capacity, a higher utilization rate and more active hours per year.

We also performed a sensitivity analysis for CA. Considering that this scenario does not have blackouts, we only focus on the conditions that deteriorate the base case (I^-, R^-, R^+ and N^+). The results show that shortages only occur in the CA scenario when there is a 10% reduction of the reservoir size (case R^-). Replacing the linear nuclear dismantling process by a step function has no significant impact on investments nor on other key variables such as the electricity price.

6. Conclusions and policy implications

In this paper, we developed an SD based model to analyze the requirements for a country such as Switzerland to drive a transition towards a 100% renewable electricity system, considering only a hydro-solar combination, with PHS to store energy. In the base case scenario, the system is unable to meet the annual demand after the start of the dismantling process. No single measure, whether slowing down the nuclear dismantling process, modifying the reservoir size, or improving technology allows the system to pass through the transition without creating significant blackouts over several years, disruptions that no society can accept. In other words, neither the likely continued fall of the capital cost for PV, nor the two regulatory options of delaying the nuclear dismantling or increasing the reservoirs results in a sustainable transition. Consequently, subsidies are required to minimize the risk of a blackout during the transition period. Furthermore, subsidizing PV makes energy storage profitable, which was not the case in the simulations without subsidies.

All the scenarios, with or without subsidies lead to higher electricity prices. For instance, we observed that in the base case the price almost doubles during the transition. This is without taking into account the cost of years of continued significant blackouts, which would create a considerable economic cost for society as a whole [67]. Introducing capacity auctions leads to lower prices compared to the base case: after a peak around 2035 prices start to decrease towards the end of the simulation ending at a level approximately 25% above the initial price. The increase in cost should not be a surprise as old, at least partly written off nuclear plants are replaced with PV capacity, which requires significant capital expenditure.

Our stylized model shows that without subsidizing PV, blackouts are inevitable. For a smooth transition, investments in both PV

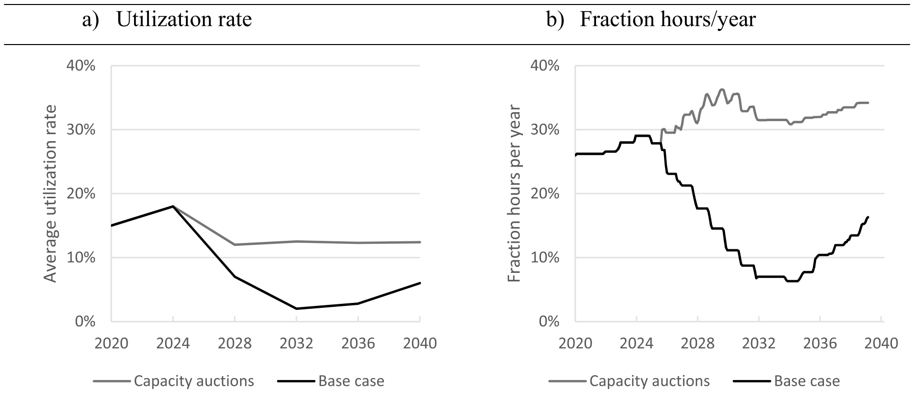

Fig. 10. PHS utilization rate.

and PHS need to be profitable. Our simulations show that this can be achieved while subsidizing only PV capacity. Indeed, in the presence of a sufficient amount of PV capacity, PHS turns profitable. Next, let us consider the practical feasibility of the proposed transition. With an annual electricity demand of 62 TWh and annual hydro-generation of 39 TWh, only 23 TWh of net additional generation are required. Assuming that 60% of PV generation is pumped, and a 20% loss factor, this implies that around 26 TWh of PV generation is required, a figure well below the estimated potential of 32 TWh by 2050 [41]. The required storage capacity can be achieved by increasing the height of current reservoir dams by 10%, which is technically possible. Regarding the need for pumping, currently there are 14 PHS plants running in Switzerland with an estimated potential pumping capacity of 369 GWh. Given Switzerland's geographical conditions, this could be doubled over the next decade by increasing the capacity of current plants and using new locations [66]. We can thus conclude that the nuclear dismantling process can be implemented without disruptions to supply by relying on a PHS and PV combination.

This stylized model has a number of limitations. In the analysis we do not consider exports and imports; as argued before, relying on cross-border trade to cover shortages or sell excess generation could be a risky strategy for governments. Recall that many countries are moving towards a significant share of PV; this will result in neighboring countries simultaneously facing an excess of electricity, making exports unprofitable, if not impossible. This may lead to extended periods of low, or even negative prices, a phenomenon that is not new in European countries such as Germany [68]. Furthermore, there are no historical examples of what would happen if several countries faced shortages at the same time. However, the recent experience among European countries within the health area is not encouraging [13].

While the model only considers capacity auctions for subsidizing capacity investment, we have also tested FITs as an alternative mechanism. However, we have not reported these results as in our model they are very similar to those of capacity auctions. One of the main differences between these two mechanisms lies in who carries the risk. In capacity auctions the regulator (and thus the final consumers) knows the cost of subsidizing a certain increase in capacity upfront and the companies carry the risk of future not developing as expected. On the contrary, with FITs the regulator bears the risk, as the generators are guaranteed a minimum price. Our model does not incorporate this risk aspect, which explains why the results of both mechanisms are similar. Furthermore, as discussed in the introduction, capacity auctions are becoming the predominant way to subsidies new investments in renewable generation across Europe.

Our results are limited by the model boundaries. We have not dealt with environmental, political, and legal changes that such a transition would require. Our results should be seen as an experiment to test different policies. It is clear that technological or political changes could affect the validity of our results. Nevertheless, we believe that our analysis has provide valid insights.

Finally, our modelling process provides a useful tool not only for Swiss policy makers, but also for other countries. This model could be adapted to study the feasibility of different energy policies for other regions or countries with a different mix facing a transition in their energy system.

Credit author statement

Ann van Ackere: Conceptualization, Juan Esteban Martinez-Jaramillo: Methodology, Juan Esteban Martinez-Jaramillo: Investigation, Juan Esteban Martinez-Jaramillo: Validation, Juan Esteban Martinez-Jaramillo: Writing – original draft. Ann van Ackere & Erik R. Larsen: Writing – review & editing. Ann van Ackere & Erik R. Larsen: Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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APPENDIX

Appendix A.1 lists the model equations. Appendix A.2 provides a graphical representation of the nonlinear relationships. The equations of the parallel model used for investment decisions (recall Section 4) are identical and thus not included here.

A.1.1 List of variable names and abbreviation

Name	Abbreviation
Annual_demand	*AD*
Annual_energy_margin	*AEM*
Annual_energy_margin forecast	*AEMF*
Annual_Natural_Inflows	*ANI*
Annual_PHS_revenue	*APR*
Annual_pumped	*AP*
Annual_unmet_demand_after PV	*AUDAPV*
Available_electricity_for pumping	*AEP*
Base Hn price	*BHnP*
Base_LCOE_base load	*BLCOEBL*
Base_LCOE_nuclear	*BLCOEN*
Base_LCOE_solar	*BLCOES*
Base_load_price	*BLP*
Base_load_technology generation_per_hour	*BLTGH*
Base_load_technology installed_capacity	*BLTIC*
Change_in_average_Price	*CAP*
Cost_per_MWh_pumped	*CMWhP*
Current_price (t-year)	*CP*
Desired_energy_margin	*DEM*
Desired_fill_rate_of_the reservoir_as_a_function_of time_of_year	*m(DFRR)*
Dmnl	*Dimensionless*
Dummy_base_load	*DBL*
Dummy_Hn	*DHn*
Dummy_intermittent	*DI*
Dummy_nuclear	*DN*
Dummy_PHS	*DPHS*
Dummy_potential_pumping	*DPP*
Electricity_demand_per_hour	*EDH*
Electricity_demand_per_hour (t + year)	*EDHY*
Electricity_price_without excess_correction	*EPWEC*
Electricity_used_for pumping	*EUP*
Energy_margin_Gap_desired-forecast	*EMG*
Excess_after_base_load	*EABL*
Excess_after_PV	*EAPV*
Gap_base_load_generation-Demand	*GBLG*
Hn_generation_capacity	*HnGC*
Hn_generation_if_Hn_first	*HnHnF*
Hn_generation_if_PHS_first	*HnPHSF*
Hn_price	*HnP*
Hn_reservoir_installed capacity	*HnRIC*
Hn_stock	*HnS*
Hn_total_generation	*HnTG*
Hn_water_release	*HnWR*
Hourly_and_monthly variation_of_solar_radiation	*v(SESR)*
Hourly_and_seasonal_demand factors	*v(HSEF)*
Hourly_average_demand	*HAD*
Hourly_PHS_revenue	*HPR*
Hourly_PHS_revenue (t + year)	*HPRY*
Hydro_availability	*HA*
Hydro_price	*HP*
Impact_of_an_increasing share_of_PV_capacity_on_the desired_energy_margin	*n(PVSCDEM)*
Impact_of_the_ratio_between current_and_the_desired_ROI on_PHS_investment_decision	*h(PHSRROI)*
Impact_of_the_ratio_between current_and_the_desired_ROI on_PV_investment_decision	*h(PVRROI)*
Impact_of_the_reservoir_fill rate_on_overflows	*f(RFR)*
Impact_of_the_reservoir_fill rate on_pumping	*g(RFR)*
Impact_of_the_reservoir fill_rate_on_the_price	*i(RFR)*
Indicator_Hn_generation_first	*IHnGf*
Initial_energy_margin	*IEM*
LCOE_base_load	*LCOEBL*
LCOE_Hn	*LCOEHn*
LCOE_nuclear	*LCOEN*
LCOE_PHS	*LCOEPHS*
LCOE_solar	*LCOES*
Market_price	*MP*
Monthly_impact_on_natural inflows	*v(MINI)*
Monthly_impact_on_Run-of-rivers_generation	*v(MIRoR)*
Natural_inflow	*NI*
Natural_inflows (t + year)	*NIY*
Need_to_subsidize_PV	*NSPV*
Normal_inflow	*NoI*
Nuclear_availability_and efficiency	*NAE*
Nuclear_generation_per_hour	*NGH*

(*continued*)

Name	Abbreviation
Nuclear_installed_capacity	*NIC*
Overflow	*O*
Phasing-out_technology dismantle	*PTD*
PHS_annual_generation	*PHSAG*
PHS_annual_income	*PHSAI*
PHS_annual_net_revenue	*PHSANR*
PHS_annual_total_cost	*PHSATC*
PHS_annual_total_hours	*PHSATH*
PHS_capital_cost	*PHSCC*
PHS_cost_of_water	*PHSCW*
PHS_default_investment_size	*PHSDIS*
PHS_desired_fill_rate	*PHSDFR*
PHS_desired_ROI	*PHSDROI*
PHS_entries	*PHSE*
PHS_generation_capacity	*PHSGC*
PHS_generation_if_Hn_first	*PHSGHnF*
PHS_generation_if_PHS_first	*PHSgPHSF*
PHS_investment_in_pumping	*PHSIP*
PHS_potential_generation	*PHSPG*
PHS_price	*PHSP*
PHS_pumping_capacity	*PHSPC*
PHS_pumping_capacity_under construction	*PHSPCUC*
PHS_pumping_dismantle	*PHSPD*
PHS_pumping_efficiency	*PHSPE*
PHS_pumping_ROI	*PHSPROI*
PHS_Ratio_ROI	*PHSRROI*
PHS_release (t + year)	*PHSRY*
PHS_released_cost	*PHSRC*
PHS_reservoir_capacity	*PHSRC*
PHS_storage_fill_rate	*PHSSFR*
PHS_total_generation	*PHSTG*
PHS_utilization_rate	*PHSUR*
PHS_water_cost	*PHSWC*
PHS_water_pumped	*PHSWP*
PHS_water_pumped (t + year)	*PHSWPY*
PHS_water_release	*PHSWR*
PHS_water_stock	*PHSWS*
PHS_yearly_pumping investment	*PHSYPI*
Price_per_MWh_PHS	*PMWhPHS*
Pumping_active	*PA*
Pumping_active (t + year)	*PAY*
Pumps_project_lifetime	*PPL*
PV_active	*PVA*
PV_active (t + year)	*PVAY*
PV_annual_generation	*PVAG*
PV_annual_income	*PVAIn*
PV_annual_income_with capacity_auction_forecast	*PVAICAF*
PV_annual_income_with_FITs forecast	*PVAIFITF*
PV_annual_investment	*PVAI*
PV_annual_net_revenue	*PVANR*
PV_annual_net_revenue_with capacity_auctions_forecast	*PVANRCAF*
PV_annual_net_revenue_with FITs_forecast	*PVANRFITF*
PV_annual_total_cost_per_MW	*PVATCMW*
PV_annual_total_cost_per_MW with_subsidies_forecast	*PVATCMWSF*
PV_annual_total_hours	*PVATH*
PV_average_utilization_factor	*PVAUF*
PV_capacity_auction_subsidy forecast	*PVCASF*
PV_capacity_forecast	*PVCF*
PV_capacity_under construction	*PVCUC*
PV_capital_cost	*PVCC*
PV_capital_cost_with_subsidies forecast	*PVCCSF*
PV_change_in utilization_factor (t + year)	*PVCUFY*
PV_construction_time	*PVCT*
PV_consumed	*PVC*
PV_cumulative_utilization factor	*PCCUF*
PV_current_utilization_factor	*PVCuUF*
PV default investment size	*PFDIS*
PV_desired_ROI	*PVDROI*
PV_dismantle	*PVD*
PV_efficiency	*PVEf*
PV_entries	*PVE*
PV_generation	*PVG*
PV_generation (t + year)	*PVGY*
PV_hourly_revenue	*PVHR*

(*continued on next page*)

(*continued*)

Name	*Abbreviation*
PV_hourly_revenue (t + year)	*PVHRY*
PV_installed_capacity	*PVIC*
PV_investment_in_new intermittent	*PVINI*
PV_lifetime	*PVL*
PV_no_subsidies_yearly revenue	*PVnSYR*
PV_O&M_expenses_per_MW per year	*PVOME*
PV_price	*PVP*
PV_price_per_MWh	*PVPMWh*
PV_project_lifetime	*PVPL*
PV_Ratio_ROI	*PVRROI*
PV_ROI_no_subsidies	*PVROInS*
PV_ROI_with_capacity_auction forecast	*PVROICAF*
PV_ROI_with_subsidies forecast	*PVROISF*
PV_utilization_factor	*PVUF*
Ratio_Hp_fill_rate/desired fill rate	*RHpFRDFR*
Ratio_required_PV_investment forecast	*RRPVIF*
Required_additional_PV capacity	*RAPVC*
Required_FIT	*RFIT*
Required_PV_annual_income forecast	*RPVAIF*
Required_PV_annual_net_profit forecast	*RPVAnPF*
Required_PV_capital_cost forecast	*RPVCCF*
Required_PV_price_per_MWh forecast	*RPVPMWhF*
Required_PV_ratio_ROI_to satisfy_PV_investment requirement	*RPVRROISPV*
Required_PV_ROI_forecast	*RPVROIF*
Reservoir_fill_rate	*RFR*
Shortage_after_base-load generation	*SABLG*
Shortage_after_Hn	*SAHn*
Shortage_after_hydro generation	*SAHG*
Shortage_after_PHS	*SAPHS*
Shortage_after_PV_generation	*SAPVG*
Shortage_after_PV_generation (t + year)	*SAPVGY*
Storage_fill_rate	*SFR*
System_hourly_electricity_price	*SHWP*
Time_to_build_pumps	*TBP*
Total_water_capacity	*TWC*
Total_water_in_reservoirs	*TWR*

A.1.2 Equations

Variables with a superscript (*) are nonlinear functions and are shown in Appendix 2.

A.1.2.1 Capacity and demand

This subsection provides the equations concerning capacity and generation for each technology, as well as for electricity demand.

A.1.2.1.1 PV capacity.

Name/Equation		Unit
	Parameter value	
PVCT	26,280	Hour
PVDIS	500	MW/hour
PVDROI	0.1	Dmnl
PVL	262,800	hour
State and associated variables		
$\frac{d(PVCUC)}{dt} = PVINI - PVE\ (PVCUC(0) = 0)$		MW
PVINI(t)=PVAI(t)		MW/ hour
$PVE(t) = \frac{PVCUC(t)}{PVCT(t)}$		MW/ hour
		MW

(*continued*)

State and associated variables	
$\frac{d(PVCUC)}{dt} = PVINI - PVE\ (PVCUC(0) = 0)$	MW
$\frac{d(PVIC)}{dt} = PVE - PVD\ (PVIC(0) = 1)$	
$PVD(t) = \frac{PVIC(t)}{PVL(t)}$	MW/ hour
Other Variables	
PVAI(t)=PVDIS* h (PVRROI)*(Figure A2.3)	MW/ hour
PVCF(t)=PVCUC (t)+ PVIC(t)	MW
$PVRROI(t) = \begin{cases} \frac{PVROISF(t)}{PVDROI(t)}, NSPV(t) > 0 \\ \frac{PVROInSF(t)}{PVDROI(t)}, otherwise \end{cases}$	Dmnl
PVROISF(t)= (PVROICAF(t)*Switch capacity auction)+(PVROIFITF(t)*(1-Switch))	Dmnl

A.1.2.1.2 PHS and hydro-storage capacity.

Name/Equation	Parameter value	Unit
PHSDIS	300	MW/hour
PHSDROI	0.1	Dmnl
PHSGC	10,000	MWh
HnGC	10,000	MWh
HnRIC	8800	GWh
NoI	3500	MWh/hour
TBP	8760	Hour
TWC	262,800	Hour
State and associated variables		
$\frac{d(PHSPCUC)}{dt} = PHSIP - PHSE\ (PHSPCUC(0) = 0)$		MW
$\mathrm{PHSIP}(t)=\mathrm{PHSYPI}(t)$		MW/hour
$\mathrm{PHSE}(t) = \frac{\mathrm{PHSPCUC}(t)}{\mathrm{TBP}}$		MW/hour
$\frac{d(PHSPC)}{dt} = PHSE - PHSD$		MW
$PHSPC(0) = 1$		
$\mathrm{PHSPD}(t) = \frac{\mathrm{PHSPC}(t)}{PL(t)}$		MW/hour
$\frac{d(PHSWS)}{dt} = PHSWP - PHSWR\ (PHSWS(0) = 880{,}000)$		MWh
$\mathrm{PHSWP}(t) = \mathrm{EUP}(t)*\mathrm{PHSPE}$		MWh/hour
$\mathrm{PHSWR}(t)=\mathrm{PHSTG}(t)$		MWh
$\frac{d(HnS)}{dt} = NI - Overflow\ (HnS(0) = 8{,}800{,}000)$		MWh
NI(t)=NoI*V (MINI)*(Figure A2.9)		MWh/hour
HnWR(t) = HnTG(t)		MWh/hour
Overflow(t) = NI(t)*f (RFR)*(Figure A2.1)		MWh/hour
Other variables		
$\mathrm{PHSRROI}(t) = \frac{\mathrm{PHSROIF}(t)}{PHSDROI(t)}$		Dmnl
PHSRC(t) = TWC-HnS(t)		MWh
PHSYPI(t)=PHSDIS* h (PHSRROI)*(Figure A2.3)		MWh/hour
$\mathrm{RFR}(t) = \frac{HnS(t) + WS(t)}{TWC(t)}$		MWh
TWR(t) = HnS (t)+ PHSWS(t)		MWh

A.1.2.1.3 Nuclear and RoR capacity.

Name/equation	Parameter value	Unit
BLTIC	3500	MW
State and associated variables		
$\frac{d(NIC)}{dt} = -PTD\ (NIC(0) = 5000)$		MW
$PTD(t) = \begin{cases} 0.057,\ 43{,}800 \le t \le 131{,}400 \\ 0, otherwise \end{cases}$		MW/hour

A.1.2.1.4 Market clearance (demand and supply).

Name/equation	Parameter value	Unit
BLTIC	3500	MW
NAE	0.68	Dmnl
PVEf	0.2	Dmnl
PHSPE	0.8	Dmnl
HA	0.9	Dmnl
HAD	6500	MWh/hour
Other variables		
GBLG(t) = BLTGH (t)+ NGH(t)-EDH(t)		MWh/hour
AEP(t) = EABL (t)+ EAPV(t)		MWh/hour
BLTGH(t)=BLTIC* v (MIRoR)*(Figure A2.9)		MWh/hour
EDH(t) = HAD*v (HSEF)*(Figure A2.7)		MWh/hour
$\mathrm{EUP}(t) = \min(\mathrm{AEP}(t), \min(\frac{\mathrm{PHSRC}(t)}{PHSE(t)}, \mathrm{PHSPC}(t)))*\mathrm{i}\ (\mathrm{RFR})*($ Figure A2.4)		MWh/hour
$EABL(t) = \begin{cases} GBLG(t), GBLG(t) < 0 \\ 0, otherwise \end{cases}$		MWh/hour
$EAPV(t) = \begin{cases} 0, PVG(t) < SABLG(t) \\ PVG(t) - SABLG(t), otherwise \end{cases}$		MWh/hour
HnHnF(t) = min(Potential generation from Hn(t), SAPVG(t))*IHnGf(t)		MWh/Hour
HnPHSF(t) = min(PGHn(t), SAPHS(t))*(1 − IHnGF(t))		MWh/Hour
HnTG(t) = HnHnf (t)+ HnPHSF(t)		MWh/Hour
$IHnGf(t) = \begin{cases} 1, HnP(t) \le PHSP(t) \\ 0, otherwise \end{cases}$		Dmnl
NGH(t)=NIC(t)*NAE		MWh/hour
PHSGHnf(t) = min(PHSPG(t), SAHn(t))*IHnGF(t)		MWh/Hour
PHSgPHSF(t) = min(PHSPAPVG(t), SAPVG(t))*(1 − IHnGF(t))		MWh/Hour
PHSPG(t) = min(PHSGC, PHSWS(t))		MWh/hour
PHSTG(t)=PHSgPHSF (t)+ PHSGHnF(t)		MWh/Hour
PVC(t) = min(PVG(t), SABLG(t))		MWh/hour
PVG(t)=PVEf*PVIC(t)* v (SESR)*(Figure A2.8)		MWh/hour
$SABLG(t) = \begin{cases} -GBLG(t), GBLG(t) < 0 \\ 0, otherwise \end{cases}$		MWh/hour
SAHn(t) = SAPVG(t)-HnHnl(t)		
SAHG(t) = max(SAPVG(t) − HnWR(t) − PHSWR(t), 0)		MWh/hour
SAPHS(t)=SAPVG(t)-PHSgPHSF(t)		MWh/Hour
SAPVG(t)=SABLG(t)-PVC(t)		MWh/hour

A.1.2.2 Bid by technology and market price. This subsection provides the parameters and equations used to calculate the bid for each technology, as well as the electricity market price.

Name/equation	Parameter value	Unit
BHnP	50	CHF/MWh
BLCOEBL	74	CHF/MWh
BLCOEN	70	CHF/MWh
BLCOES	120	CHF/MWh
PHSCC	500,000	CHF/MW
PPL	25	Year
PVCC	992,000	CHF/MW
PVOME	15,000	CHF/MW/Year
PVPL	30	Year

Data from IRENA (2017) [69], Fu, Feldman and Margolis (2018) [70] and Renew Economy (2017) [71].

A.1.2.2.1 PV Bid.

Name/equation	Unit
State variables	
$\mathrm{PVA}(t) = \mathrm{DI}(t)$	Dmnl/hour
$\mathrm{PVAY(t)} = \mathrm{PVA\ (t\text{-}8760)}$	Dmnl/hour
$\frac{d(PVAG)}{dt} = PVG - PVGY \qquad (PVAG(0) = 0)$	MWh
$\frac{d(PVATH)}{dt} = PVA - PVAY \qquad (PVATH(0) = 0)$	Dmnl
$\mathrm{PVCUFY(t)} = \mathrm{PVCuUF(t\text{-}8760)}$	Dmnl/hour
$\frac{d(PCCUF)}{dt} = PVCuUF - PVCUFY \qquad (PCCUF(0) = 0)$	Dmnl
$\mathrm{PVCuUF}(t) = \mathrm{v\ (SESR)}$*(Figure A2.8)	Dmnl/hour
$\mathrm{PVGY(t)} = \mathrm{PVG\ (t\text{-}8760)}$	MWh/hour
$\mathrm{PVHR}(t) = \mathrm{SHEP}(t)*\mathrm{PVC}(t)$	CHF/hour
$\mathrm{PVHRY(t)} = \mathrm{PVHR\ (t\text{-}8760)}$	CHF/hour
$\frac{d(PVnSYR)}{dt} = PVHR - PVHRY \qquad (PVnSYR(0) = 0)$	CHF
Other Variables	
$DI(t) = \begin{cases} 1, & PVG(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$\mathrm{LCOES}(t) = \mathrm{BLCOES}*\mathrm{DI}(t)$	CHF/MWh
$\mathrm{PVAIn}(t) = \mathrm{PVPMWh}(t)*\mathrm{PVATH}(t)*\mathrm{PVAUF}(t)*\mathrm{PVEf}$	CHF/Year
$PVAUF(t) = \begin{cases} 0, & PVATH(t) = 0 \\ \frac{PCCUF(t)}{PVATH(t)}, & otherwise \end{cases}$	Dmnl
$\mathrm{PVANR}(t) = \mathrm{PVAI}(t)\text{-}\mathrm{PVATCMW}(t)$	CHF/MW/Year
$\mathrm{PVATCMW}(t) = \frac{PVCC(t)}{PVPL(t)} + PVOME(t)$	CHF/MW/Year
$PVPMWh(t) = \begin{cases} 0, & PVAG(t) = 0 \\ \frac{PVnYR(t)}{PVAG(t)}, & otherwise \end{cases}$	CHF/MWh
$\mathrm{PVROInS}(t) = \frac{PVANR(t)}{\mathrm{PVCC}}$	Dmnl

A.1.2.2.2 PHS Bid.

Name/equation	Unit
State and associated variables	
$\frac{d(APR)}{dt} = HPR - HPRY \quad (APR(0) = 0)$	CHF
HPR(t)=SHEP(t)*PHSTG(t)	CHF/hour
HPRY(t) = HPR(t-8760)	CHF/hour
$\frac{d(PHSAG)}{dt} = PHSWR - PHSRY \quad (PHSAG(0) = 0)$	MWh
$\frac{d(PHSATH)}{dt} = PA - PAY \quad (HSATH(0) = 8,800,000)$	Hours/year
$\frac{d(PHSCW)}{dt} = PHSWC - PHSRC \quad PHSCW(0) = 140,800,000$	CHF
PHSRY(t) = PHSWR (t-8760)	MWh/hour
PHSRC(t)=CMWhP(t)*PHSWR(t)	CHF/hour
PHSWC(t)=PVP(t)*$\frac{\text{PHSWP}(t)}{\text{PHSE}(t)}$	CHF/hour
PA(t) = DP(t)	hours
PAY(t) = PA (t-8760)	Hours
Other Variables	
$CMMWhP(t) = \begin{cases} \frac{PHSCW(t)}{PHSWS(t)}, & PHSWS(t) > 0 \\ 0, & otherwise \end{cases}$	CHF/MWh
$DPHS(t) = \begin{cases} 1, & PHSWR(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DPP(t) = \begin{cases} 1, & EUP(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
LCOEPHS(t) = PHSP(t)*DPHS(t)	CHF/MWh
PHSAI(t)=PHSUR(t)*PMWhPHS(t)*PHSE(t)*PHSATH(t)	CHF/MW/year
PHSANR(t)=PHSAI(t)-PHSATC(t)	CHF/MW/year
PHSATC(t) $= \frac{PHSCC(t)}{PPL(t)} + \text{CMWhP}(t)*\text{PHSATH}(t)*\text{PHSE}(t)*\text{PHSUR}(t)$	CHF/MW/year
PHSDFR(t) = m (DFRR)*(Figure A2.5)	Dmnl
PHSPROI(t) $= \frac{PHSANR(t)}{PHSCC(t)}$	Dmnl
PHSSFR(t) $= \frac{PHSWS(t)}{PHSRC(t)}$	Dmnl
PHSUR(t) $= \frac{PHSWP(t)}{PHSPC(t)*PHSE(t)}$	Dmnl
$PMWhPHS(t) = \begin{cases} 0, PHSAG(t) \le 0 \\ \frac{APHSR(t)}{PHSAG(t)}, otherwise \end{cases}$	CHF/MWh
RHpFRDFR(t) $= \frac{PHSSFR(t)}{PHSDFR(t)}$	Dmnl
SFR(t) $= \frac{HnS(t)}{TWC(t)}$	Dmnl

A.1.2.2.3 Hydro-storage, RoR and Nuclear Bid.

Name/equation	Unit
Other variables	
$DBL(t) = \begin{cases} 1, & BLTGH(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DHn(t) = \begin{cases} 1, & HnWR(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DN(t) = \begin{cases} 1, & NGH(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
LCOEBL(t) = BLCOEBL*DBL(t)	CHF/MWh
LCOEHn(t) = HnP(t)*DHn(t)	CHF/MWh
LCOEN(t) = BLCOEN*DN(t)	CHF/MWh

A.1.2.2.4 Market price.

Stocks and associated variables	
Name/equation	Unit
CAP(t)=SHEP(t)	CHF/MWh/hour
CP(t) = CPY(t-8760)	CHF/MWh/hour
$\frac{d(MP)}{dt} = CAP - CP \ (MP(0) = 70)$	CHF/MWh
Other variables	
BLP(t) = $max(LCOEN(t), LCOWBL(t))$	CHF/MWh
EPWEC(t) = $max(max(BLP(t), PVP(t)), HP(t))$	CHF/MWh
HnP(t) = BHnP*g (RFR)*(Figure A2.2)	CHF/MWh
$HP(t) = max(LCOEHn(t), LCOEPHS(t))$	CHF/MWh
PHSP(t)=CMWhP(t)* g (RFR)*(Figure A2.2)	CHF/MWh
PVP(t) = LCOES(t)*(DPP*(1- i (RFR)*(Figure A2.4)))	CHF/MWh

A.1.2.3 Subsidies

This subsection provides the parameters and equations used to calculate the subsidies for PV.

Name/equation	Parameter value		Unit
IEM	0.033		CHF/MWh
State and associated variables			
Equation			**Unit**
$\frac{d(AD)}{dt} = EDH - EDHY \ (AD(0) = 0)$			MWh
EDHY(t) = EDH (t-8760)			MWh/hour
$\frac{d(ANI)}{dt} = NI - NIY \ (ANI(0) = 0)$			MWh
NIY(t) = NI(t-8760)			MWh/hour
$\frac{d(AP)}{dt} = PHSWP - PHSWPY \ (AP(0) = 0)$			MWh
PHSWPY(t) = PHSWP(t-8760)			MWh/hour
$\frac{d(AUDAPV)}{dt} = SAPVG - SAPVGY \ (AUDAPV(0) = 0)$			MWh
SAPVGY(t) = SAPVG (t-8760)			MWh/hour
Other Variables			
$AEM(t) = \begin{cases} \frac{ANI(t)+AP(t)-AUDAPV(t)}{AD(t)}, t>8760 \\ IEM, otherwise \end{cases}$		Dmnl	
$AEMF(t) = \begin{cases} \frac{ANI(t)+APF(t)-AUDAPVF(t)}{AD(t)}, t>8760 \\ IEM, otherwise \end{cases}$		Dmnl	
DEM(t) = n (PVSCDEM)*(Figure A2.6)		Dmnl	
EMG(t) = DEM(t)-AEMF(t)		Dmnl	
$NSPV(t) = \begin{cases} 0, EMGF(t)>0 \\ 1, otherwise \end{cases}$		Dmnl	
PVAICAF(t)=PVPMWhF(t)*PVATH(t)*PVAUF(t)*PVEf		CHF/MW/year	
PVAIFITF(t)=NSPV(t)*(RFIT (t)+ PVPMWhF(t))*PVATH(t)*PVAUF(t)*PVEf		CHF/MW/year	
PVANRCAF(t)=PVAICAF(t)-PVATCMWSF(t)		CHF/MW/year	
PVANRFITF(t)=PVAIFITF(t)-PVATCMW(t)		CHF/MW/year	
$\mathrm{PVATCMWSF}(t) = \frac{PVCCSF(t)}{PVPL(t)+PVOME(t)}$		CHF/MW/year	
PVCASF(t)=(PVCC-RPVCCF(t))*NSPV(t)		CHF/MW	
PVCCSF(t)=PVCC-PVCASF(t)		CHF/MW	
$\mathrm{PVROICAF}(t) = \frac{PVANRCAF(t)}{PVCCSF(t)}$		Dmnl	
$\mathrm{RRPVIF}(t) = \frac{RAPVC(t)}{PVDIS(t)}$		Dmnl	
$RAPVC(t) = \begin{cases} \frac{AUDAPV(t)}{PVE(t)*PVAUF(t)*PVATH(t)}, t>8760 \wedge AEMF(t)<0 \\ 0, otherwise \end{cases}$		MW	
RFIT(t) = RPVPMWhF(t)-PVPMWhF(t)		CHF/MWh	
$RPVAIF(t) = \begin{cases} PVATCMW(t) + RPVANPF(t), PVATCMW(t)+RPVANPF(t)>0 \\ 0, otherwise \end{cases}$		CHF/MW/year	
RPVANPF(t) = RPVROIF(t)*PVCC		CHF/MW/year	
$RPVCCF(t) = \begin{cases} PVCC(t), \ RPVROIF(t)<0 \\ \frac{\mathrm{PVAICAF}(t)+\mathrm{PVOME}}{\mathrm{RPVROIF}(t)+\frac{1}{PVPL(t)}}, \ otherwise \end{cases}$		CHF/MW	
$\mathrm{RPVPMWhF}(t) = \begin{cases} 0, \ t<8760 \\ \frac{\mathrm{RAIF}(t)}{\mathrm{PVATH}(t)*\mathrm{PVAUF}(t)*\mathrm{PVEf}}, otherwise \end{cases}$		CHF/MWh	
RPVRROISPV(t) = h^{-1}(PVRROI)*(Figure A2.3)		Dmnl	
RPVROIF(t) = RPVRROISPV(t)*PVDROI		Dmnl	

A.2 Graphical representation of nonlinear functional relationships.

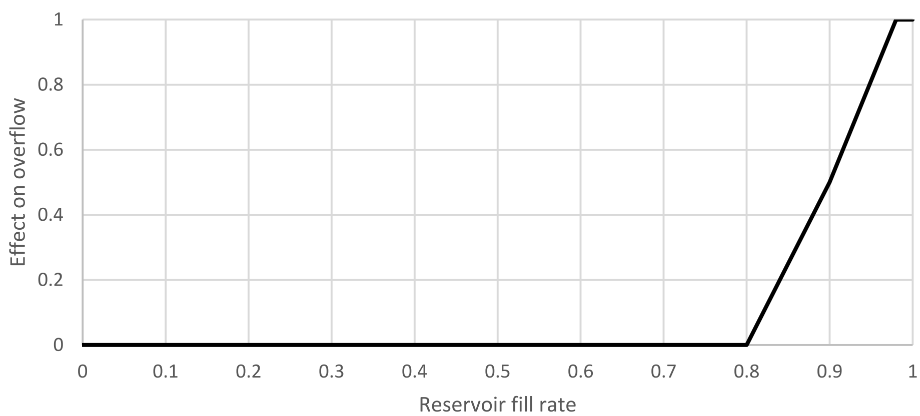

Fig. A2.1. Impact of the reservoir fill rate on overflows f(RFR).

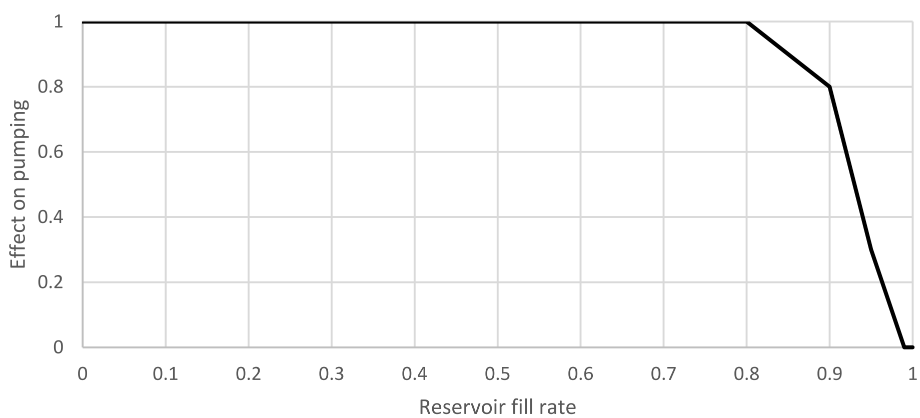

Fig. A2.2. Impact of the reservoir fill rate on pumping g(RFR).

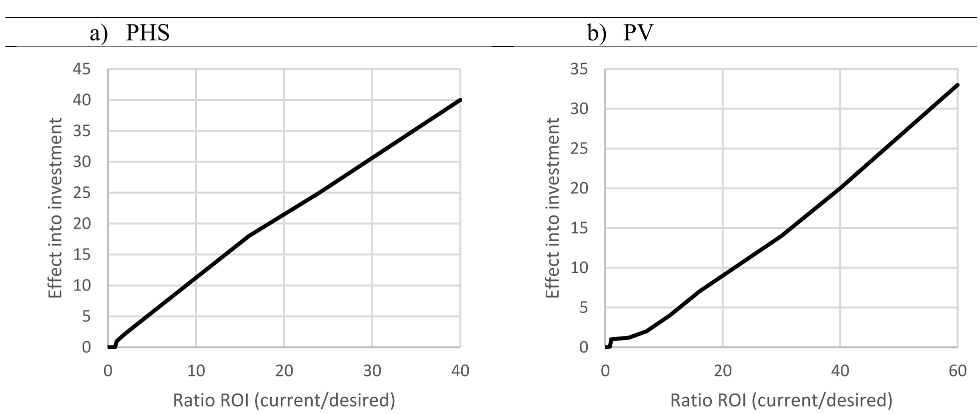

Fig. A2.3. Impact of the ratio between current and the desired ROI on investment decision, i.e., h(PHSRROI) and h(PVRROI).

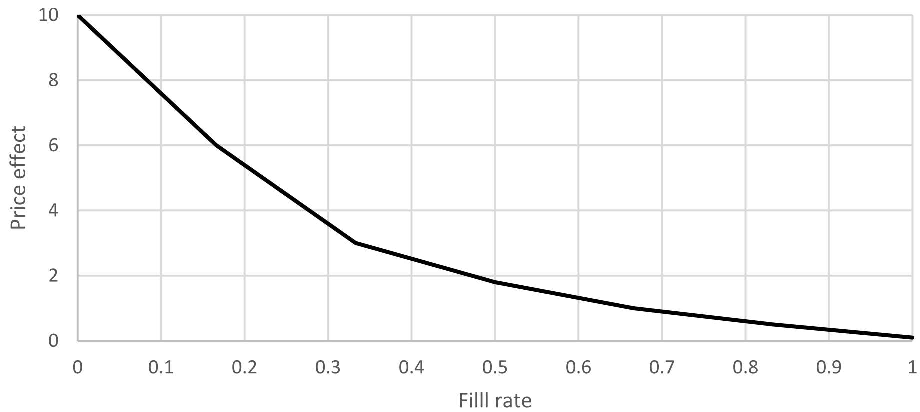

Fig. A2.4. Impact of the reservoir fill rate on the price i(RFR).

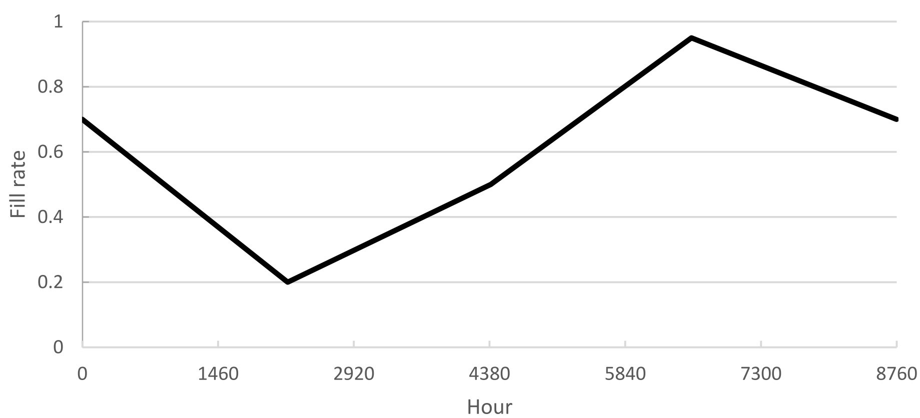

Fig. A2.5. Desired fill rate of the reservoir as a function of time of year m(DFRR).

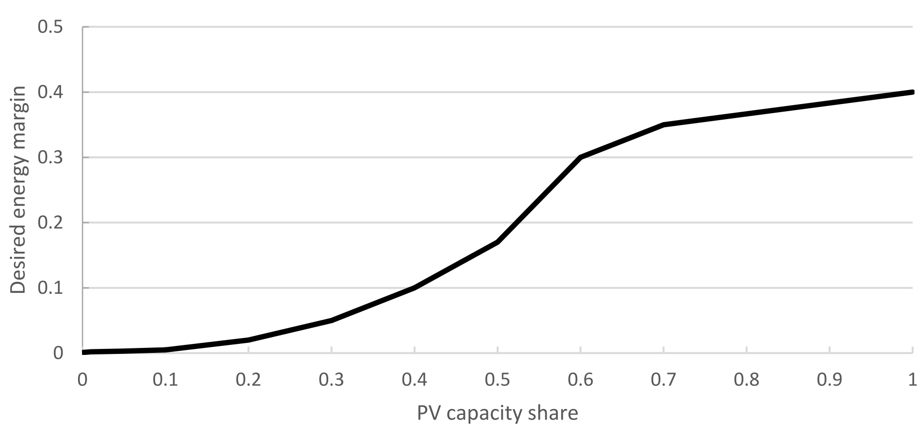

Fig. A2.6. Impact of an increasing share of PV capacity on the desired energy margin n(PVSCDEM).

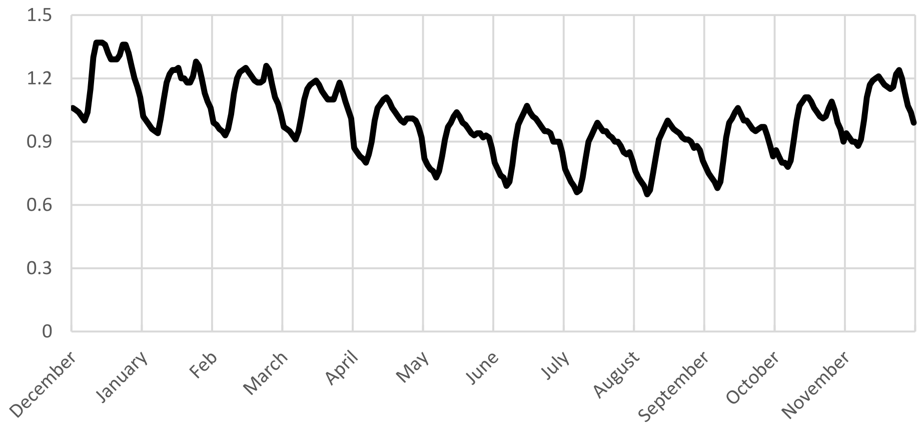

Fig. A2.7. Hourly and seasonal demand factors v(HSEF).

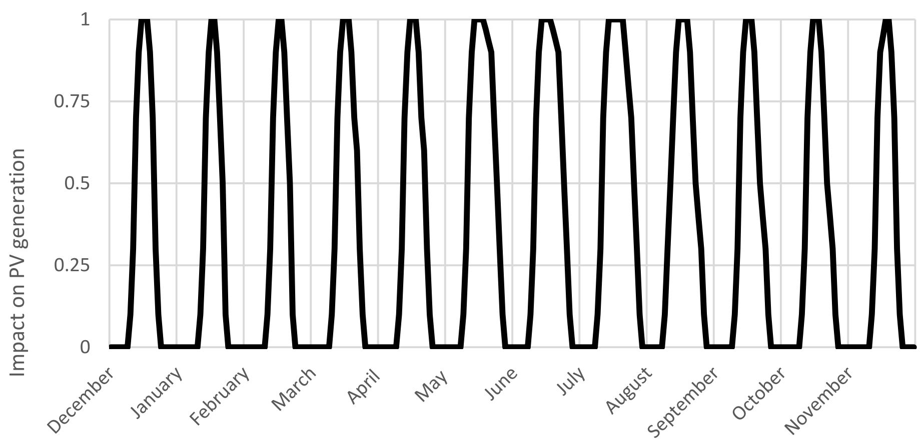

Fig. A.2.8. Hourly and monthly variation of solar radiation v(SESR).

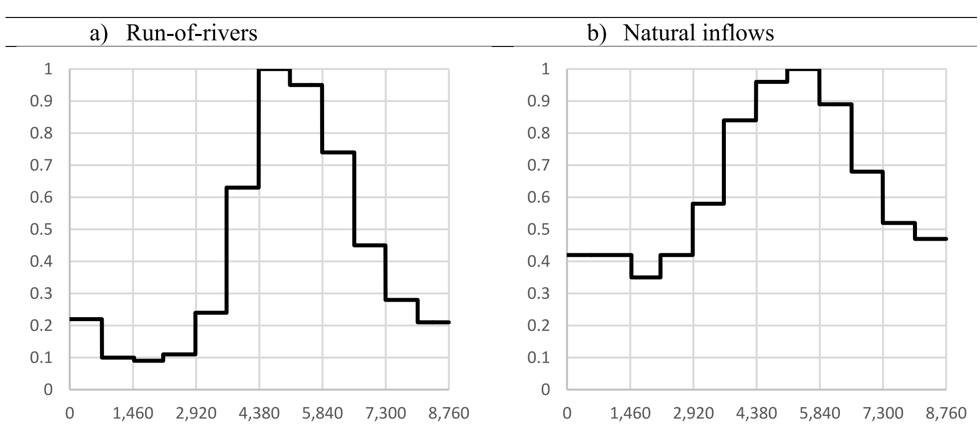

Fig. A2.9. Monthly impact on natural inflows and RoR generation, i.e., V(MIRoR) and V(MINI).

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